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Economic Regulatory Administration

Voluntary Guideline for the Cost of Service Standard Under the Public Utility Regulatory Policies Act of 1978; Public Hearing

DEPARTMENT OF ENERGY

Economic Regulatory Administration

[Docket No. ERA-R-80-29]

Voluntary Guideline for the Cost of Service Standard Under the Public Utility Regulatory Policies Act of 1978 Proposed Guideline and Public Hearing

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Notice of proposed voluntary guideline.

SUMMARY: Title I of the Public Utility Regulatory Policies Act of 1978 (PURPA or the Act) establishes certain Federal purposes and policy standards for the regulation of electric utilities. It imposes a set of obligations upon State regulatory authorities and certain nonregulated electric utilities relative to their consideration of the Federal standards established by sections 111 and 113.

Under section 131 of PURPA, the Secretary of Energy is authorized to prescribe voluntary guidelines respecting the Federal standards. The Appendix of this Notice is the proposed voluntary guideline respecting the cost of service standard established by section 111 of PURPA. Written comments will be received and two public hearings will be held with respect to the proposed guideline.

DATES: Comments by 4:30 p.m., November 21, 1980. Requests to speak by November 5, 1980, 4:30 p.m. Public hearings dates: San Francisco, California hearing—November 13, 1980, 9:30 a.m.; Washington, D.C. hearing—November 18, 1980, 9:30 a.m.

ADDRESSES: All comments addressed to: Department of Energy, Office of Public Hearings Management, Docket No. ERA-R-80-29, 2000 M Street, N.W., Room 2313, Washington, D.C. 20461.

Requests to speak addressed to: Department of Energy, Office of Public Hearings Management, Docket No. ERA-R-80-29, 2000 M Street, N.W., Room 2313, Washington, D.C. 20461.

Hearing Locations: San Francisco, California hearing: Crocker/Hopkins Room, Ramada Inn/Fisherman's Wharf, 590 Bay Street, San Francisco, California 94133.

Washington, D.C. hearing: Department of Energy, 2000 M Street, N.W., Room 2105, Washington, D.C. 20461

FOR FURTHER INFORMATION CONTACT:

Stephen S. Skjei, Division of Regulatory Assistance, Office of Utility Systems, Economic Regulatory Administration, Department of Energy, 2000 M Street, N.W., Room 4016D, Washington, D.C. 20461, telephone (202) 653-3913.

William L. Webb, Office of Public Information, Economic Regulatory Administration, Department of Energy, 2000 M Street, N.W., Room B-110, Washington, D.C. 20461, telephone (202) 653-4055.

Mary Ann Masterson, Office of General Counsel, Department of Energy, 1000 Independence Avenue, S.W., Room 1E-258, Washington, D.C. 20585, telephone (202) 252-9516.

SUPPLEMENTARY INFORMATION:

I. Background

On November 8, 1978, the President signed into law the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. 95-617, 92 Stat. 3117 *et seq.* (16 U.S.C. 2601 *et seq.*) as one part of the National Energy Act.

PURPA requires State regulatory authorities and certain nonregulated electric utilities to determine whether implementation of the ratemaking standards established by section 111, and adoption of the policy standards established by section 113, (except with respect to 113(b)(4)) would be appropriate to carry out the purposes set forth in section 101. The three purposes established by section 101 of PURPA are to encourage:

(a) Conservation of energy supplied by electric utilities;

(b) The optimization of the efficiency of use of facilities and resources by electric utilities; and

(c) Equitable rates to electric consumers.

One of the ratemaking standards established by section 111 directly addresses the fundamental concept of cost of service. Section 111(d)(1) establishes, as a Federal standard, that rates charged to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing such service. Further definition and elaboration of this standard is provided by section 115(a) which establishes several special rules for considering the cost of service standard. In considering this standard, the costs of service must be determined on the basis of methods which permit (to the maximum extent practicable) identification of differences in cost-incurrences attributable to time of use and to differences in the customer, demand and energy components of cost. In addition, State regulatory authorities and covered nonregulated electric utilities, in prescribing such methods, must take into account the cost consequences of providing additional kilowatt-hours of energy and adding capacity to meet peak kilowatt demand.

Cost of service is also an integral part of the remaining ratemaking standards established in section 111(d). Sections 111(d)(2)-(6) set forth standards for declining block, time of day, seasonal and interruptible electric rates, and load management techniques; four of these Federal standards incorporate the underlying requirement that rates track the costs of service of the utility, while the load management standard specifies a cost-effectiveness criterion.

Section 131 of PURPA authorizes the Secretary of Energy to prescribe voluntary guidelines respecting consideration of the PURPA standards. These standards apply to thoses electric utilities whose annual retail sales exceed 500 million kilowatt-hours in any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

II. Guideline on the PURPA Cost of Service Standard

The purpose of this voluntary guideline is to assist State regulatory authorities and covered nonregulated electric utilities in their consideration of the cost of service standard set forth in section 111(d)(1) of PUPRPA, as well as in their consideration of the remaining standards in section 111(d), each of which is tied to the cost of service.

The guideline addresses five major issues that are germane to consideration of the cost of service standard and the decision to implement that standard in terms of the purposes of Title I of the Act. These issues are: (a) Marginal vs. embedded costs; (b) estimation of marginal cost; (c) adjustments to marginal cost-based rates; (d) alternative marginal costing methodologies; and (e) other issues.

The guidance set forth herein is advisory in nature and is not legally binding. It constitutes DOE's opinion on the issues that should be addressed when considering whether it is appropriate to implement the cost of service standard to carry out the purposes of Title I of the Act. the guideline complements and is fully consistent with the other activities undertaken by DOE pursuant to PURPA.

III. Cost of Service and the Purposes of PURPA

The three PURPA Title I purposes provide a necessary set of national policy criteria to guide the decisions made by a State regulatory authority or covered nonregulated electric utility in considering the section 111 and section 113 standards. In this regard, PURPA supplements the legal authority and

responsibility of State regulatory authorities and covered nonregulated electric utilities in those jurisdictions where existing State law provides insufficient authority to implement the PURPA standards. The three purposes also provide suplemental criteria for judicial review, in accordance with section 123 of PURPA, of State regulatory decisions regarding the Federal standards.

PURPA requires State regulatory authorities and covered nonregulated electric utilities to consider and determine whether the implementation of the cost of service standard established by section 111 of PURPA is appropriate to carry out the three purposes of Title I—end-use conservation, utility efficiency and equitable rates. In constructing the guideline proposed in the Appendix, DOE has adhered to those working definitions of the three purposes previously used in DOE intervention testimony. Based on the Act, itself, and its legislative history, these definitions are:

A. End-Use Conservation

The conservation purpose focuses on the end-use of electricity. End-use conservation does not necessarily mean minimizing the total use of electric energy or any other form of energy. Rather it is aimed at eliminating "wasteful" consumption or that consumption unjustified because it would involve a commitment of scarce resources valued in excess of the value to end-users of such consumption. Conservation is encouraged when end-users are faced with prices that reflect the actual costs of the resources used in producing electricity. Electricity would then be consumed only to the extent that the value of additional electricity consumption to consumers is equal to or exceeds the cost to society of producing the additional electricity.

This concept of conservation of electricity bears an obviously important relationship to the cost of service and other ratemaking standards set forth under Title I of PUPRA, since all six ratemaking standards are based on the concept the rates should reflect the cost consequences of providing additional kilowatt-hours of electric energy and kilowatts of electric demand. Such rate designs would encourage the societally appropriate degree of consumption and, by implication, conservation.

B. Utility Efficiency

The utility efficiency purpose of PURPA is directed at minimizing the total resource cost associated with the production of electricity in the quantities and at times that consumers wish to purchase it at prices which discourage wasteful (i.e., non-economic) use.

The utility efficiency purpose relates to the conservation of the resources used in the generation, transmission and distribution of electric power, rather than to efficient use of electricity itself, although optimal electricity supply presupposes economically efficient end-use. Utility efficiency specifically includes conservation of primary energy sources, especially scarce imported fossil fuels, through the substitution of more plentiful and domestically available energy resources (e.g., coal and nuclear). In furtherance of these objectives, the concept of utility efficiency would embrace development of alternative generating technologies, consistent with the economic merits of such technologies.

C. Equitable Rates

The equitable rates purpose deals with equity emong consumers rather than with the more traditional regulatory concern of determining equity between consumers and suppliers of electricity. As a general proposition, equity among electricity consumers is best achieved when rates for individual customers and classes of customers are based on the cost consequences of their individual decisions to consume or conserve additional amounts of electricity. Such cost-based rates would avoid wasteful subsidies between users.

Both PURPA and the Conference Report, however, contemplate exceptions to the principle that equitable rates should be based on the cost of service. These exceptions would tend to protect customers from higher rates. Such exceptions may result, however, in some degree of wasteful usage, and should be pursued only when undue economic hardships would otherwise result.

Within the context of equity, finally, it should be stressed that the use of marginal costs in designing electric rates is not intended to raise or lower the rates for any particular class(es) of customers. To the contrary, the goal is to ensure that any given customer is charged a rate reflective of the economic consequences of consumption decisions.

IV. The Appropriateness of Marginal Costs

In an economy where resources are scarce, consumers are best served, i.e., consumer satisfaction is maximized, when the resources needed to produce competing goods and services are allocated among them in a manner that is consistent with the relative value to consumers of the competing products. Thus, additional scarce resources should be used to produce additional units of any product only if consumers are willing to pay a price for those additional units that is at least equal to the value of the resources needed to produce it. If consumers are not willing to pay such a price, the scarce resources should be used to produce additional units of some alternative product (for which consumers are willing to pay a price equal to or greater than the value of the resources used in production).

In a market economy such as ours, the price system plays a major role in the allocation of resources among competing uses and, consequently, in the determination of what and how much is produced and how goods and services are distributed among consumers. Consumers reveal their preferences for goods through the prices they are willing to pay; producers reveal their costs of producing these goods through the prices at which they are willing to sell these goods. To ensure that prices achieve the desired result of steering scarce resources into the production of goods at levels which maximize consumers' satisfaction in the consumption of those goods, it is important that prices accurately reflect the value of scarce resources used in the good's production. This happens when a consumer is faced with prices which reflect marginal cost.

In the case of electricity prices, a competitive market would reflect the costs of providing additional kilowatt-hour usage and kilowatt demand and would permit consumers to make sensible decisions about whether to consume more or less electricity at any given time. Rational consumption decisions made when prices reflect the marginal cost of electricity would affect the use of alternative fuels, including renewable resources, and substitution of conservation measures for electricity consumption.

A competitive market does not exist, however, in the electric utility industry. Instead, electric rates are set by public regulators rather than by consumer and producer decisions in a competitive marketplace. In the past, the focus of public rate regulation was on establishing the revenue requirement of a utility—the general level of revenues necessary for a utility to cover its fixed and operating costs and to earn a "fair" rate of return on its invested capital. Because the primary objective of rate design was to set rates which generated the required revenue, there was little concern about ensuring that consumers understand the cost consequences of their decisions to consume additional

amounts of electricity. Section 115(a) of PURPA, however, stipulates that State regulatory authorities and covered nonregulated electric utilities shall now take into account the cost consequences of additional kilowatt-hour usage and peak kilowatt demand in considering the cost of service.

Electric utility rates which reflect marginal costs best confront consumers with the cost consequences of their usage decisions. Faced with such price signals, electric consumers will tend to use the amount of electric service that is justified by its resource costs and such consumption behavior will, in turn, serve to carry out the three purposes of Title I of PURPA. Marginal cost-based pricing will encourage the proper amount of end-use conservation in the sense that no electricity will be consumed when its value to the consumer is less than the value of the resources required to produce it. Utility efficiency will also be furthered by basing electricity prices on the marginal costs of service, because such pricing will result in the least cost production of electricity, in the quantities and at the times that consumers decide to purchase it when faced with the consequences of their decisions. Finally, the equitable rates purpose is also furthered because marginal cost-based pricing would result in equal treatment for all customers who impose the same costs on the utility system.

V. The Proposed Guideline

This guideline addresses the five general issues which DOE believes are central to consideration of the cost of service standard and the decision to implement that standard in terms of the purposes of Title I of PURPA:

(a) Marginal costs vs. embedded costs;
(b) Estimation of marginal costs;
(c) Adjustments to marginal costs;
(d) Alternative marginal costing methodologies; and
(e) Other issues.

Following is a summary of each of these issues as proposed in the guideline:

A. Marginal Costs vs. Embedded Costs

Section 115(a) of PURPA, which establishes special rules for the section 111(d)(1) cost of service standard, requires that the approach to determining the cost of service account specifically for the functional breakdown of total costs and the time variation in these costs. Furthermore, in prescribing such approaches, State regulatory authorities and covered nonregulated electric utilities must take into account the increase in total costs that results from providing additional kilowatt-hours of energy and additional capacity to meet peak demand. It is DOE's conclusion that section 115(a) requires, in effect, that marginal costs be taken into account in the course of considering the cost of service standard.

B. Estimation of Marginal Costs

The measurement of the costs associated with providing another kilowatt-hour and another kilowatt (marginal cost) is a function of the specific characteristics of the particular utility system. Among the most significant characteristics that must be considered are the fuel mix and level of capacity in relation to the load. The guideline provides guidance concerning the appropriate estimation of marginal costs for four general utility cases which are representative of electric utility systems. The guideline does not, however, detail any preferred method(s) for calculating and applying marginal costs; public comment on this point is specifically solicited.

C. Adjustments to Marginal Costs

When designing rate structures on the basis of marginal costs, it may be necessary to make certain adjustments to marginal costs. First, adjustments will often be necessary to meet the total revenue requirement determined on the basis of embedded costs. If the amount of excess or deficient revenue is small, the rate adjustment to eliminate these excesses or deficiencies would result in small changes and would have insignificant effects on utility customers' consumption decisions. If the amount of excess or deficient revenue is large, rate adjustments should be made in a way which is consistent with the end-use conservation, utility efficiency and equitable rates purposes of PURPA (and with applicable State laws) and which is practical. With regard to adjustments to account for the existence of non-optimal pricing in significantly related markets, especially gas and oil, DOE does not believe that the existence of a substantial problem has been demonstrated. Lastly, environmental and other social costs associated with the production of electric power at the margin should be included in calculating the marginal cost of electricity to the extent they can be quantified. However, a significant proportion of those external or social costs have already been internalized through regulation.

D. Marginal Costing Methods

The selection of a marginal costing method and its specific application should be baded on a careful analysis of the characteristics of the electric utility and its customers, and the characteristics of each marginal costing methodology. DOE proposes several criteria to be considered by regulatory authorities in the process of selecting a method.

E. Other Issues

The adoption of marginal cost pricing does not necessarily lead to the implementation of any particular rate structure. Selection of any of the section 111 rate structures to further the three purposes of PURPA should depend on the electric utility's marginal costs, the costs of implementation, and the probable consumption responses and resource savings.

Customer classes should be defined in a way which minimizes the differences among customers within a class and maximizes the differences among classes in terms of the following service characteristics: Voltage delivery levels, geographic location, consumption by time of use, the relative diversity of demand vis-a-vis the time of system peak and total usage.

Adjustments between rates and marginal costs should be permitted only to meet the revenue requirement and to avoid exceptional economic hardships. Any such adjustments should be done in a way which does minimal damage to the benefits to be realized from rate structures based on marginal costs.

VI. Written Comments and Public Hearing Procedures

A. Written Comments

The public is invited to participate in this proceeding by submitting to DOE's Economic Regulatory Administration (ERA) information, views or arguments with respect to the proposal set forth in the Appendix to this Notice. Comments should be submitted by 4:30 p.m., November 21, 1980, to the address indicated in the "ADDRESSES" section of this Notice and should be identified on the outside of the envelope and on documents submitted with the designation: "Proposed Voluntary Guideline on the PURPA Cost of Service Standard, Docket No. ERA–R–80–29." Five copies should be submitted. All comments received will be available for public inspeciton in the DOE Reading Room GA–152, James Forrestal Building, 1000 Independence Avenue, S.W., Washington, D.C. 20585, and the ERA Office of Public Information, Room B–110, 2000 M Street, NW., Washington, D.C. 20461, between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday.

Pursuant to the provisions of 10 CFR 10005.11, any person submitting information which he or she believes to

be confidential and which may be exempt by law from public disclosure should submit one complete copy and 15 copies from which information claimed to be confidential has been deleted.In accordance with the procedures established at 10 CFR 1004.11, DOE shall make its own determination with regard to any claim that information submitted be exempt from public disclosure.

B. Public Hearing

(1) *Procedures for Request to Make Oral Presentation.* The times and places for the hearings are indicated on the "DATES" and ADDRESSES" sections of this Notice. Any person who has an interest in this proposed guideline or represents a person, group or class of persons that has an interest, may make a written request for an opportunity to speak at the public hearing. Requests to speak must be sent to the address shown in the "ADDRESSES" section and be received by November 5, 1980. The request should include a telephone number where the speaker may be contacted through the day before the hearing.

All persons participating in the hearing will be so notified on or before November 10, 1980 for the Washington, D.C. and San Francisco, California hearings. Speakers should submit 100 copies of their hearing testimony for distribution at the Washington, D.C. hearing by 4:30 p.m., on November 10, 1980, to the Office of Public Hearings, Management, U.S. Department of Energy, Room 2313, 2000 M Street, NW., Washington, D.C. 20461, and bring 100 copies of their hearing testimony to the San Francisco, California hearing at 8:30 a.m. on November 13, 1980.

(2) *Conduct of the Hearing.* ERA reserves the right to schedule particpants' presentations and to establish the procedures governing the conduct of the hearing. ERA may limit the length of each presentation based on the number of persons requesting to be heard. ERA encourages groups that have similar interests to choose one appropriate spokesperson qualified to represent the views of the group.

ERA will designate an official to preside at the hearing. This will not be a judicial-type hearing. Questions may be asked only by those conducting the hearing. At the conclusion of all initial oral statements, each person who has made an oral statement will be given the opportunity, if time permits, to make a rebuttal statement. Rebuttal statements will be given in the order in which the initial statements were made and will be subject to time limitations.

Questions to be asked at the hearing should be submitted in writing to the presiding officer. The presiding officer will determine whether the question is relevant, and whether time limitation permit it to be presented for answer. The question will be asked of the witness by the presiding officer. The presiding officer will announce any further procedural rules needed for the proper conduct of the hearing.

ERA will have a transcript made of the hearings and will retain the entire record of the hearings, including the transcrpit. The record will be available for inspection at the DOE Freedom of Information Office, Room GA–152, James Forrestal Building, 1000 Independence Avenue, SW., Washington, D.C. 20585, and the ERA Office of Public Information, Room B–110, 2000 M Street, NW., Washington, D.C. 20461, between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday. A copy of the transcript may be purchased from the reporter.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95–617, 92 Stat. 3117 *et seq.* (16 U.S.C. 2601 *et seq.*); Department of Energy Organization Act, Pub. L. 95–91 (42 U.S.C. 7101 *et seq.*))

Issued in Washington, D.C., on August 27, 1980.

Hazel R. Rollins,

Administrator, Economic regulatory Administration.

Appendix—PURPA Voluntary Guideline Number 4: Cost of Service

A. Introduction

This voluntary guideline addresses consideration of the cost of service standard established by section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA or the Act). It sets forth the issues that the Department of Energy (DOE) considers to be of major importance in addressing the cost of service standard and is intended to assist State regulatory authorities and covered nonregulated electirc utilities in meeting their legal obligations under PURPA Title I in a consistent and rational manner. This guideline is voluntary and does not in any way modify or condition existing State regulatory authority and nonregulated electric utility practices or applicable State laws.

B. Coverage of the Guideline

This guideline covers the determination of the cost of providing electirc service as that cost of service relates to consideration of the standard established by section 111(d)(1) of PURPA. The voluntary guideline does not in any way modify or condition the rules which have been promulgated by the Federal Energy Regulatory Commission (FERC) under section 133 of PURPA, which require periodic reporting of marginal and embedded cost information, or those which have been promulgated by the FERC under section 210 of PURPA, which require electirc utilities to buy power from small power producers and cogenerators at a rate equal to the utility's avoided cost. This guideline does not apply in situations involving either the sale of electric energy to qualifying cogenerators and small power producers or the purchase of electric energy from such facilities by covered electric utilities, if such sales and purchases are covered by section 210 of PURPA and rules promulgated by the FERC.

C. Definitions

As provided in this guideline, except as otherwise specifically provided—

"Class" means, with respect to electric consumers, any group of such consumers who have similar characteristics of electric energy use.

"Electric consumer" means any person, State agency or Federal agency, to which electirc energy is sold other than for purposes of resale.

"Electric utility" means any person, State agency, or Federal agency which sells electric energy.

"Federal agency" means an executive agency (as defined in section 105 of Title 5 of the Unites States Code).

"Load management technique" means any technique (other than a time of day or seasonal rate) to reduce the maxium kilowatt demand on the electric utility, including ripple or radio control mechanisms, and other types of interruptible electric service, energy storage devices, and load-limiting devices.

"Nonregulated electric utility" means any electric utility other than a State regulated electric utility.

"Person" means an individual, partnership, corporation, unincorporated association or any other group, organization or entity.

"Rate" means (a) any price, rate, charge or classification made, demanded, observed or received with respect to sale of electric energy by an electric utility to an electric consumer, (b) any rule, regulation or practice respecting any such rate, charge or classification, and (c) any contract pertaining to the sale of electric energy to an electric consumer.

"Ratemaking authority" means authority to fix, modify, approve or disapprove rates.

"Rate schedule" means the designation of the rates which an electric utility charges for electric energy.

"Secretary" means the Secretary of Energy.

"State" means a State, the District of Columbia, and Puerto Rico.

"State agency" means a State, political subdivision thereof, and any agency or instrumentality of either.

"State regulated electric utility" means any electric utility with respect to which a State regulatory authority has ratemaking authority.

"State regulatory authority" means any State agency which has ratemaking authority with respect to the sale of electric energy by any electric utility (other than such State agency), and in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority, such term means the Tennessee Valley Authority.

D. Organization and Content

The guideline is organized around five general issues that DOE considers relevant in the consideration of the cost of service standard and the proper use of the costs of service in establishing electric utility rates that carry out the purposes of Title I of PURPA:

1. marginal costs vs. embedded costs;
2. Estimation of marginal costs;
3. Adjustments to marginal costs;
4. Alternative marginal costing methodologies; and
5. Other issues.

E. Marginal Costs vs. Embedded Costs

Section 111(d)(1) of PURPA establishes as Federal standard that "rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the cost of providing electric service to such class * * *." The five other ratemaking standards established in section 111(d) require that the specific rate structures in question (i.e., declining block rates, time of day rates, seasonal rates, interruptible rates) and load management techniques be designed to reflect the cost of service.

Section 115(a) of PURPA establishes special rules for the cost of service standard set forth in section 111(d)(1) of the Act. Specifically, section 115(a) requires that, to the maximum extent practicable, methods used to determine the cost of providing electric service shall permit:

(1) Identification of differences in cost-incurrence for each class of electric consumers attributable to daily and seasonal time of use of service; and

(2) Indentification of differences in cost-incurrence attributable to differences in customer, demand and energy components of cost;

Further, in prescribing such methods State regulatory authorities and covered nonregulated electric utilities shall take into account:

(3) The extent to which total costs to an electric utility are likely to change if additional capacity is added to meet peak demand relative to base demand; and

(4) The extent to which total costs to an electric utililty are likely to change if additional kilowatt-hours of electric energy are delivered to electric consumers.

Taken as an integrated set, these four factors require the use of a costing method capable of identifying marginal costs by time of use, basic cost classification, and customer class. State regulatory authorities and covered noregulated electric utilities, however, may select their preferred marginal cost method from among several practical methods, including those identified by the Electric Utililty Rate Design Study and other such studies.

1. *Marginal costs.* In general, marginal cost is the additional cost incurred (or the cost saved) if one more (or one less) kilowatt or kilowatt-hour of electricity is produced. In other words, marginal costs reflect the change in total costs occasioned by a change in consumption.

The Glossary: *Electric Utililty Ratemaking and Load Management Terms,* prepared for the Electric Utility Rate Design Study by the Electric Power Research Institute, includes the following definition: "Marginal cost: The change in total costs associated with a unit change in quantity supplied (i.e., demand or energy)."

This fundamental characteristic does not apply to embedded costs. The costs a utility incurs to respond to changes in customer usage are not measured by either the average accounting costs for the fuels it purchases or the average accounting costs for its fixed facilities (generating plant, transmission system, distribution system). The actual costs a utility incurs are measured by the price or prices it must pay for additional fuel, the expenditures it must make for new fixed facililties, and any other changes in its total costs of service.

Accordingly, rates based on marginal costs, but not rates based on average accounting or embedded costs, indicate to users the cost consequences of changes in their consumption. Because of this quality, marginal cost-based rates further the end-use conservation, utility efficiency, and equitable rates purposes set forth in section 101 of PURPA.

Moreover, only marginal cost accounts for all four of the cost characteristics specified in section 115 (a) of PURPA. As noted earlier, the concept of marginal costs is entirely consistent with the requirements of sections 115(a)(2) (A) and (B). In addition, it is consistent with the three basic cost classifications of electric service (customer, demand and energy) specified in section 115(a)(2). Marginal costing approaches attribute costs to the different characteristics of service (such as demand, energy and voltage levels) used by different customers. Each customer and customer class is then charged for its use of these different characteristics of electric utility service in accord with the costs of these characteristics. Cost responsibility is assigned to each customer class on the basis of its use of electric utility services and in accord with the cost to the utility of providing more or less of each of these services.

Finally, section 115(a) of PURPA requires identification of the differences in cost incurrence by daily and seasonal time of use.

Most of the time variation in the cost of providing electric service occurs in the provision of the bulk power supply—both capacity and energy—and this variation is directly related to the pattern of loads that must be met by the provision of the bulk power supply. Some time variation is costs also results from the provision of subtransmission and distribution services, though this contribution is relatively minor when compared to the time-varying costs of bulk power supply. Customer-related costs, i.e., the costs of connecting customers to the electrical system, have no time variation.

Marginal cost, by its very definition, will vary by season and by time of day, depending on the load that must be met at each point in time. In the case of bulk power supply, for example, the short-run marginal cost is the cost of meeting the last kilowatt of load in each hour by running the least efficient generating unit needed to provide that last kilowatt. Because the system load varies from hour to hour, and because the operating costs of the various generating units may also vary significantly, the short-run marginal cost of providing energy will vary hour by hour and so by time of day and by season. When growth in peak demand creates the need for additional generating and associated bulk power transmission capacity, while maintaining a given level of system reliability, the marginal cost of the needed capacity is the minimum capital cost required to meet that increment of load during the peak period.

2. *Embedded (average) costs.* Embedded costs do not meet three of the four PURPA section 115(a) requirements for considering the cost of service

standard. Specifically, embedded costs, by definition, do not take into account either the change in total costs which results from providing additional capacity to meet peak demand and/or additional kilowatt-hours of energy or the time variation in these costs. Embedded costs do not adequately capture the change in total costs associated with the provision of additional service by time of day or by season.

In addition, while the embedded cost method does permit the total costs of service to be allocated to the major functional components of costs and these functional components to be allocated to the different classes of customers, these costs are based entirely on past decisions rather than on the cost consequences of current decisions to consume additional units of service.

3. *Electric utility cost structure.* This section describes the major characteristics of the production and sale of electric power which affect the costs of the major functional components of electric utility service. These characteristics and their effect on costs must be reflected in the methods selected by State regulatory authorities and covered nonregulated electric utilities in accordance with section 115(a). Electric utility costs can be separated into three major categories, corresponding to the three major components of electric service: (1) Bulk power supply costs; (2) the costs of subtransmission and distribution, exclusive of connection costs; and (3) the costs of connecting customers to the system and of maintaining those connections.

Electric utility costs are fundamentally shaped by two characteristics of the production and sale of electric power. First, electric utilities are obligated to meet maximum loads (except during emergency outages) whenever they occur. Second, as a general proposition, power cannot conveniently be stored. These two factors require that the utility maintain sufficient generation, transmission and distribution capacity to serve the maximum coincident loads placed on each of these three parts of the electrical system.

This requirement, in itself, would pose no special supply problems if loads were relatively constant across all hours of the year. Typically, however, they are not. There is usually a wide range between the maximum and minimum hourly loads imposed upon an electrical system over any given day, month or year. This is largely because loads tend to vary with such environmental conditions as temperature, weather and periods of daylight—all of which vary significantly over the course of a day or a year.

Electric utilities respond to these three characteristics—the obligation to meet maximum demands whenever they occur; the inability to conveniently store electric power; and the wide variation in electric loads—by using different types of capacity for different periods of time. Their use of different types of capacity is directed toward minimizing the total costs of meeting any given system load while maintaining system reliability. As a general proposition, it is most economical to meet loads of short duration by installing generating capacity that will have the lowest possible capital costs. On the other hand, it is most cost-effective to meet loads of relatively long duration by installing generating capacity with the lowest possible running costs.

The marginal costs of bulk power supply depend upon the utility's pattern of loads in three important respects. First, the need to maintin reliability during peak demand periods usually determines the total amount of generating capacity that must be installed, and growth in peak demand is the usual cause for capacity additions.[1] Second, an electric utility must consider the entire pattern of loads, and not merely peak demands, in deciding what mix of generating plants is most appropriate. Finally, the way in which existing generation capacity is dispatched to minimize total costs depends directly on the pattern of loads that must be served, and the resulting dispatch procedure determines the running costs of the utility.

Transmission-related costs (both capital and operation and maintenance costs) as traditionally defined should properly be broken into two categories—bulk power supply transmission and subtransmission. Bulk power supply transmission costs are incurred from central station baseload generating facilities to load center. Subtransmission costs are incurred in the process of moving electric power at much lower voltages from major substations to the distribution system. The factors that are responsible for the incurrence of generation costs (peak demand, pattern of loads and cost-minimization opportunities) are also responsible for the incurrence of bulk power transmission costs.

Subtransmission and distrubution costs (both capital and operation and maintenance costs) are incurred in the process of delivering bulk power supplies to customers at usable voltage levels. There are three aspects of these costs that directly affect the magnitude of subtransmission and distribution costs.

(a) Losses occur in the process of transforming, transmitting and distributing electric power, and the magnitude (and so the costs) of these losses is directly related to the number of kilowatt-hours delivered at each voltage delivery level;

(b) The cost of connecting any given customer to the distribution and transmission network are independent of the amount of electricity consumed by that customer. The total of these costs is related directly to the number, sizes, and voltage levels of customers connected to the system and not to their kilowatt-hour usage or kilowatt demand; and

(c) Certain operating expenses, such as customer accounts, expenses and customer service and information expenses, are directly related to the number and type of customers that take service from the utility.

F. Estimation of Marginal Costs

In any market, the price that leads to the efficient use of resources is a marginal cost price. This is true whether or not the market is competitive. In a competitive unregulated market, market forces themselves act to ensure pricing at marginal cost levels. If prices were above marginal costs, producers would be attracted by the profits obtained from additional sales and would expand their production of the good or service. Production would be expanded until the price consumers are willing to pay for that good or service falls to the level equivalent with marginal costs. Similarly, the price of a good or service could not remain below the marginal cost of production indefinitely. Producers would suffer losses on every sale made at a price which was lower than marginal costs and would contract their production until the price consumers were willing to pay for that good or service rose and became equal to marginal costs.

In a regulated industry, however, a major goal of regulation should be to ensure that, to the maximum extent practicable, the regulated prices reflect marginal costs. In determining the

[1] Two exceptions to this general rule must be noted. For some utilities, "excess capacity" suitable for peaking purposes will be available during the peak period for the foreseeable future, and capacity additions may be attributable solely to the need to serve, the total kilowatt-hour energy requirement at the least cost. For other utilities, capacity additions may be highly unlikely in the foreseeable future. Both of these situations imply that capacity costs are not relevant on the margin during any rating period and that there should be no capacity charges in the associated rates, because capacity additions are not attributable to kilowatt demand.

marginal costs for an electric utility system, it is often useful to employ the two closely related concepts of "avoided" costs and "opportunity" costs. Marginal costs are the costs incurred or the costs saved if one more unit of a good or service is produced. Avoided costs, as used by the FERC in its cogeneration rulemaking for section 210 of PURPA (45 FR 12214, February 25, 1980), are the incremental costs to an electric utility of the electric energy or capacity (or both) which, but for the purchase from a cogenerator, the utility would need to obtain from traditional sources. Thus, avoided costs are marginal costs; they are the costs a utility saves or does not incur because it does not itself produce an additional kilowatt or kilowatt-hour.

The opportunity cost associated with any good or service is the market value of the alternatives which are foregone because that good or service is produced or made available in a certain manner. For example, the opportunity cost of a kilowatt-hour might be measured by the market value of the fuel used in generating it. The fuel used to generate electricity can be used for other purposes, such as heating homes. The opportunity cost associated with using it to generate electricity is defined by the inability to use it for these other purposes. Because the value of the fuel in alternative uses is reflected in the price consumer are willing to pay for it (and thus in its market price), the market price of the fuel reflects its opportunity cost.

While a kilowatt-hour of electric energy cannot be created without burning fuel, a kilowatt of capacity can in some cases be made available without any opportunity cost. If an electric utility system has substantial excess capacity at any point in time, the opportunity cost of a kilowatt at that time is zero. Nothing is sacrificed, no resources are used, no alternatives are foregone if kilowatt is made available.

Each of the three concepts of cost suggests that, in the electric utility industry, the measurement of the costs associated with providing both another kilowatt-hour and another kilowatt is affected by the mix and level of capacity in relation to load. The following four general capacity/load cases may be distinguished:

(1) Systems in which capacity is to be added for reliability purposes.

(2) Systems in which capacity is to be added to lower the costs of meeting load.

(3) Systems in which capacity is to be added to provide additional energy.

(4) Systems in which no capacity is to be added. These are discussed in turn.

1. *Capacity additions to improve reliability.* For systems in which additional capacity must be built only for reliability purposes, marginal energy costs may be measured by the operating costs of the most expensive generating unit used in any time period—that is, the marginal running costs, sometimes referred to as "system lambda."

Marginal capacity costs may be measured by calculating the capital costs, net of any associated fuel savings, of the generating unit (peaker, cycling unit or baseload plant) which will meet the increment in demand in the least cost manner. For example, if a combustion turbine will be built to meet the need for additional capacity, the marginal capacity costs is that of this unit. However, in many cases the least cost alternative for adding capacity is through construction of a baseload or cycling unit, because the higher capital costs of such a unit are more than offset by its operating costs. The savings in fuel costs should therefore be credited against the fixed cost of the new unit, i.e., marginal capacity cost will be measured by the capital cost (annual carrying charges) of the plant less the associated fuel savings generated by using the new plant.

2. *Capacity additions to lower total cost.* In the second situation in which additional capacity is built to reduce the total cost of meeting a load, i.e., new additions replace existing capacity, marginal energy costs are measured by the operating costs of the most expensive unit used in any rating period. Marginal capacity costs in this situation are zero because the utility has excess reserves.

The utility does not need to build new capacity to meet an increment in demand. In other words, there is no opportunity costs associated with making one more kilowatt available. The capacity needed to meet an increment in demand is already in place (excess reserves) and must be paid for (carrying cost) whether they are used or not. Only if the capacity can be sold as firm power might there be an opportunity cost associated with its use by utility customers.

3. *Capacity additions to provide additional energy.* For systems in which capacity is added only to provide additional energy, e.g., a system with extensive hydroelectric capacity, marginal capacity cost are also zero. There is no capacity cost to the utility because the utility has excess reserves at peak and is adding the new unit to meet an increase in total energy requirements not an increase in demand. Marginal energy cost may be measured by an opportunity cost concept if sales are made or by assigning the full capital cost of the new capacity to the energy cost account (because it is being used to provide energy) and calculating a per kilowatt-hour charge.

4. *No capacity additions.* Marginal capacity costs are also zero, or defined by opportunity costs, in utility systems which have an excess of technically efficient capacity, and would probably not plan to build new capacity for an extended period of time (a decade or more). However, if all of the excess capacity can be sold to another utility or utilities, there is an opportunity cost associated with an increment in demand and it is this cost which should be used in setting rates. An increment in system demand reduces earnings from sales and thus causes a loss in revenue from such sales. This loss in earnings is an opportunity cost for the system and can be used to define marginal capacity costs.

Marginal energy costs in this situation may be defined either by opportunity costs or system lambda. If sales can be made to a grid or powerpool at a price in excess of the system lambda, it may not be appropriate to use system lambda as a measure of marginal energy cost. In this, situation the sale price determines the opportunity cost of providing an incremental kilowatt-hour. Where such sales cannot be made or can be made only to a limited extent (which does not require use of the entire excess capacity), system lambda is an appropriate measure of opportunity costs or marginal costs.

G. Adjustment to Marginal Costs

When designing rate structures on the basis of marginal costs, to conform with the ratemaking standards set forth in section 111 of PURPA, it may be necessary to make certain adjustments. Considerable attention has been focused on the choice of alternative adjustment procedures and the practical problems necessitating such adjustments. The major adjustments at issue fall into three categories: (1) Adjustments to meet the total revenue requirement determined, in rate of return regulation, on the basis of total embedded costs; (2) adjustments to account for inconsistencies in the application of marginal cost pricing principles between electric and related markets; and (3) adjustments to account for external costs.

When such adjustments are necessary, for whatever reason, the ratemaker should remember that the purpose of marginal cost pricing is to encourage efficient use of energy and capacity by providing rate incentives to consumers. It is not the intent of

marginal cost pricing to redistribute the revenue requirement among customers or customer classes. In fact, attempts to redistribute the revenue requirement may have serious negative impacts on efficiency.

1. *Revenue related adjustments.* Total allowed revenues will generally continue to be determined by State regulatory authorities and covered nonregulated electric utilities on the basis of historical embedded costs. Rates based purely on the marginal costs of service will not normally recover exactly the same revenues that are allowed on an embedded cost basis. Over-collection of revenues will occur when marginal costs are determined to exceed the average embedded costs for a utility; conversely, undercollection will occur when marginal costs are less than embedded costs. In most cases it will be necessary to adjust some rate elements up or down to design a rate structure that will recover the established revenue requirement.

This need to make revenue-related adjustments does not, however, preclude the application of marginal costing principles in designing the structure of electric rates. For some utilities, rates based purely on marginal cost should result in only small amounts of excess (or insufficient) revenue. Adjustments to eliminate these excess (or insufficiencies) would result in small changes and would have insignificant effects on consumers' decisions regarding when and how much electricity to consume.

For situations in which the amount of excess (or insufficient) revenue is relatively large, the necessary rate adjustments can be made in a variety of practical ways which are consistent with the end-use conservation, utility efficiency and equitable rates purposes of PURPA, as well as consistent with applicable State law.

Customer charges may be reduced or eliminated to offset any excess revenues that might result from marginal cost-based rates. Alternatively, an inverted rate structure may be used in which the tailblock rate reflects marginal costs and the initial block or blocks are set at a low enough level to meet the revenue requirement. Additionally, a proportionate reduction of rates that preserves the structure of marginal costs by time of day or by season may be appropriate. where undercollection would occur, additional revenues can be generated by increasing customer charges, which would have minimal effects on consumers' decisions of when and how much electric power to consume. Further, the undercollection can be eliminated by a proportionate increase of functional prices that preserves the structure of marginal costs.

The use of rates that reflect marginal costs need not create undue financial harships for any class of utility customers. If rates based on marginal cost would result in an excessive increase in the revenue responsibility of any one customer class (or of an identifiable group of customers within a class), then rate adjustments can be made so as to provide, over a period of years, a gradual transition toward rates fully reflective of the structure of marginal costs. This approach to mitigating excessive economic burdens is fully consistent with the legislative history of PURPA, which identifies certain exceptions (phased implementation, temporary exemptions and lifeline rates) to the concept that equitable rates should be based on the cost of service. Phased implementation of and temporary exemptions from the section 111 ratemaking standards provide a transition period for affected customers to make the necessary adjustments in their electricity consumption to reduce any exceptional burdens resulting from the implementation of rates based on marginal costs.

In selecting a procedure to adjust marginal cost-based rates, State regulatory authorities and covered nonregulated electric utilities should give consideration to the effects of the adjustments on the use of generating capacity, rate stability and the resulting economic impacts on electric consumers. In addition, it is important that these adjustments be made so as to result in rate structures with minimum deviation from the structure of marginal costs.

2. *Inconsistency among related markets.* Another issue concerning the application of marginal cost pricing to the electric utility industry relates to the extent to which the prices of related commodities reflect their marginal costs. Theoretically, the existence of non-optimal pricing (prices that deviate from marginal cost) in related markets can affect the degree to which overall economic efficiency can be attained by basing electric rates on marginal costs.

DOE does not believe that the existence of a substantial problem in this regard has been demonstrated. The benefits to a utility of basing electric rates on marginal costs, in any event, are not likely to be appreciably offset by such a problem.

3. *Adjustments to account for social costs.* The production and consumption of some commodities, including electricity, can result in external costs that are imposed on individuals or groups who are neither the producers nor the consumers of that commodity. The environmental pollution resulting from the production of electricity or the consumption of gasoline in private automobiles are examples of these external or social costs. If these marginal social costs are not paid by the producers of the commodity, they are not included in its price. When there are important social costs that are associated with the production or consumption of a commodity, and the price of the commodity reflects only the marginal private costs that are incurred in its production, that commodity will be overproduced and overconsumed.

Although there are external or social costs associated with the production of electric power, to a large extent these social costs have already been internalized and accounted for in the determination of electric utility rates. As a result of both Federal and State environmental and safety regulations, electric utilities have been required to incur considerable expense to reduce these social costs; and these expenses for pollution abatement and the maintenance of public health and safety are now included by the utilities and their regulators in the prices that consumers must pay for electricity.

Other important social costs associated with the production of electricity at the margin may be found to exist, which have not been imposed on the producers of electricity. In such cases if the magnitude of these social costs can be quantified, these costs should be included in the calculation of marginal costs.

H. Alternative Marginal Costing Methodologies

Several methodologies exist for the calculation of electric utility marginal costs. The prescription of a marginal costing method by a State regulatory authority or covered nonregulated electric utility should be make in light of the characteristics of the electric utility and its customers, and the characteristics of each marginal costing methodology.

DOE does not believe that any single approach to calculating (or applying) marginal costs ought to be universally followed. Substantial flexibility in selecting a method that is appropriate to a given situation was clearly contemplated by the Congress and is strongly endorsed by DOE. In selecting a preferred marginal cost method, State regulators and covered nonregulated electric utilities should bear in mind that the aim of marginal cost pricing is, quite simply, to establish rate incentives that

reflect the economic benefits of efficient use of energy and capacity. Ratemakers should not allow this straightforward goal to become obscured by excessively theoretical deliberations or unnecessarily complicated methodologies.

1. The method should accommodate a practicable resource planning process for the utililty and should recognize the ability to substitute capital for fuels.

2. The method should yield an appropriate functional breakdown of marginal costs and an assignment of costs to the loads that are responsible for imposing those costs on the system.

3. The method should measure marginal costs over either the short-run or long-run, as deemed appropriate.

4. The method should accommodate consideration of pool-wide marginal costs when the utility is a member of an efficiently dispatched powerpool.

5. The method should permit all parties to the ratemaking proceeding to have access to the estimation procedures employed, thus permitting verification and assessment of the cost estimates.

Finally, and by definition, the method must be forward-looking in that it must estimate the cost consequences of current consumption decisions over the period when the rates under consideration will be in effect.

I. Other Issues

1. *Rates structure standards.* Subsections 111(d) (2) through (6) of PURPA established Federal standards with respect to declining block rates, time-of-day rates, seasonal rates, interruptible rates, and load management techniques. These standards provide that: Declining block rates that are not cost-based shall be eliminated; time-of-day rates shall be established if cost-effective, where costs vary by time-of-day; seasonal rates shall be established where costs vary by season; cost-based interruptible rates shall be offered to commercial and industrial customers; and load managment techniques shall be offered to consumers when such techniques are determined to be practicable, cost-effective, reliable and to provide useful energy or capacity managment advantages to the electric utility.

Adoption of marginal cost pricing does not necessarily lead to the implementation of any particular rate structure. Which of the rate structures specified in section 111 of PURPA will be appropriate for implementation will depend on the functional and time-varying structure of marginal costs that is determined. In addition, specific cost-effectiveness determinations must also be made for time-of-day rates and load management techniques. Similarly, implementation of seasonal rates, while not explicitly requiring a cost-effectiveness test, does imply that the measured seasonal differential in costs should be great enought warrant the implementation of such rates. In short, State regulatory authorities and covered nonregulated electric utilities must analyze the structure of marginal costs, the costs of implementation, and the probable consumption responses and resource cost saving when determining whether implementation of any specific marginal cost-based rate structure will serve to carry out the three purposes of Title I of PURPA.

2. *Definition and us of customer classes.* To realize the end-use conservation, utility efficiency and equitable rates objectives set forth in Title I of PURPA, the differences in the costs of providing service to different classes of electric consumers should be determined on the basis on the basis of marginal costs. Most of the costs of providing electric service to the several classes of electric consumers are incurred in the provision of bulk power supply (i.e.,. the generation and transmission of electricity at high voltage levels), and these cost at the margin will be the same at generation level for all individual customers who take service at the same point in time. Thus, bulk power supply costs should be determined at the system level, and the unit costs of use of this functional component of service should be the same for all customers, save for differential losses due to differences in voltage delivery levels. On the other hand, customer classes should be used in the determination of other functional components of costs and for the purpose of translating the marginal costs of the various functional components of service into a structure of rates that properly reflects the differences in the costs of providing service to different classes of electric customers.

In defining customer classes, care should be taken to yield groupings that are internally homogeneous with respect to the critical cost-causative attributes of loads (e.g., contributions to system peak demand) and the proxies for these attributes (e.g., noncoincident maximum billing demands) that will be used for billing purposes. In determining the proper definition of customer classes for costing and rate design purposes, DOE recommends that State regulatory authorities and covered nonregulated electric utilities analyze the following service characteristics with respect to marginal costs:

(a) Voltage delivery levels;

(b) Geographic location to the extent that it is related to differences in distrubution costs;

(c) Consumption by time of use;

(d) The relative diversity of demand vis-a-vis the time of the system peak to ensure that diversity benefits generated by each class of similar customers are retained by the customers in that class; and

(e) Total usage to permit examination of the relationship between the volume of use and the cost of service.

3. *Deviations from marginal costs.* In its discussion of section 111(c), the Conference Report suggests phasing the implementation of the section 111 standards or granting temporary exemptions from implemented standards to mitigate significant economic hardships that would result from sudden shifts in electric utility rates. In addition, section 114 requires each State regulatory authority and covered non-regulated electric utility to consider the appropriateness of a lifeline rate for essential residential needs that would be lower than a rate based on the cost of service.

If such deviations are deemed appropriate by State regulators or covered nonregulated electric utilities, DOE encourages the use of approaches that minimize the discrepancies between marginal costs and the structure of electric utility rates, particularly for those uses, in any customer class, deemed to be relatively price elastic. DOE believes that any such departures from marginal cost should be designed in a manner to do minimal damage to the benefits of rates based on marginal costs.

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